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U.S. Energy Flow–1994

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Contents

Abstract

Energy consumption in 1994 increased for the fourth year in a row, reaching an all-time high. It was associated with a robust economy, low inflation, and low unemployment rates. Of the populous states, California lagged substantially behind the national recovery. Consumption in all major end-use sectors reached historic highs. Transmission of electrical power by the utilities increased almost 3%. However, this understates the increase of the total amount of electricity used in the nation because the amount of electricity used "in-house" by a growing number of self-generators is unrecorded.

Imports of both fossil fuels and electricity increased. About half of the total oil consumed was imported, with Saudi Arabia being the principal supplier. Domestic oil production continued to decline; however, the sharp decline in Alaskan production was slowed. The increase in the demand for natural gas was met by both a modest increase in domestic production and imports from Canada, which comprised 10% of supply. The residential/commercial sector is the largest single consumer of natural gas; however, use by electric generators has increased annually for the past decade. The regulated utilities increased their consumption 11% in 1994.

The year saw hearings before the California Public Utilities Commission (CPUC) on the potential sale of electricity by out-of-state producers directly to consumers within the state. The proposal was that direct sales to industrial and large commercial customers would begin in 1996 and to residential consumers in 2002. The hearings were watched closely by the nation's utilities because California was the first state to begin implementing the provisions of the Energy Policy Act of 1992, which called for changes in the traditional role that utilities play in electrical power production, transmission, and sales. Although a ruling from the CPUC was not forthcoming in 1994, California utilities began preparing for what they view as an inevitable change in their monopolistic, regulated industry by improving efficiencies and cutting costs to become more competitive in the future.

The year was noteworthy for the U.S. nuclear power industry. Work was halted on the last nuclear power plant under construction in the country. Because of the retirement of aged and poorly performing nuclear plants and because of improved efficiencies, the capacity factor for the remaining 109 operable plants reached a record 74%.

Introduction

United States energy flow charts tracing primary resource supply and end use have been prepared by members of the Energy Program and Planning groups at the Lawrence Livermore National Laboratory since 1972.[1,2] These charts are convenient graphical devices to show relative size of energy sources and end uses because all fuels are compared on a common energy unit basis. The amount of detail on a flow chart can vary substantially, and there is some point where complexity begins to interfere with the main objectives of the presentation. The charts in this report have been drawn for clarity and to be consistent with the assumptions and style used previously.

Energy Flow Charts

Figures 1 and 2 are energy flow charts for calendar years 1994 and 1993,[3] respectively. (These figures are printed as the center spread, pages 10 and 11.) The 1994 chart is based on provisional data published by the Energy Information Administration of the U.S. Department of Energy.[4] Conventions and conversion factors used in the construction of the charts are given in the Appendix. For comparison with earlier years, consumption of energy resources is given in Table 1. These data in many instances contain revisions of data previously reported in this series.

Comparison of Energy Use with 1993 and Earlier Years

For the fourth consecutive year, energy consumption registered an increase. The total for 1994 was 85 quads (10^{15} Btu), up approximately 1.7% (Table 1). The national economy was robust by most economic indicators (Table 2). Inflation was slightly more than 2%, compared to 2.2% in 1993, and unemployment at the year's end fell to 5.7% from 6.7% during December of the previous year.[5] California continued to lag the nation in recovery from the recession; however, the decline in the 1994 state unemployment rate from 10.1% in January to 7.7% in December was a substantial improvement.

The principal end-use sectors—residential/commercial, industrial, and transportation—increased their energy consumption by 1.6, 1.7, and 2.1% respectively, exclusive of electrical losses (Table 1). All reached historical highs. The amount of electricity transmitted by the utilities increased approximately 2.8%, in keeping with similar annual increases in the 1990—1994 period. The amount of utility-generated and utility-transmitted electricity is in fact an underestimation of electrical use in the country; the amount of electricity produced and used in-house by a growing number of private enterprises goes largely unrecorded.

Table 1. Comparison of annual energy use in United States.

	Quads (10^{15} Btu)							
	1987	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**
Natural gas production	17.14	17.60	17.85	18.36	18.28	18.37	18.74	19.37
Net imports	0.99	1.30	1.39	1.55	1.67	1.94	2.40	2.58
Crude oil and NGL								
Domestic crude & NGL	19.89	19.54	18.28	17.74	18.01	17.59	16.90	16.42
Foreign imports (incl. products and SPR)	14.17	15.75	17.17	17.12	16.34	16.91	18.51	19.11
Exports	1.63	1.74	1.84	1.82	2.13	2.00	2.11	1.99
SPR storage reserve[a]	0.17	0.11	0.12	0.04	–0.10	0.03	0.07	0.03
Net consumption[b,c]	32.87	34.22	34.21	33.55	32.85	33.53	33.84	34.65
Coal production (including exports)	20.14	20.74	21.35	22.46	21.57	21.59	20.22	22.00
Electricity								
Hydroelectric (net)								
Utility	0.85	0.76	0.90	0.96	0.94	0.82	0.90	0.83
Imports	0.46	0.32	0.11	0.02	0.23	0.29	0.30	0.44
Geothermal & other (net)	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03
Nuclear (gross)	4.91	5.66	5.68	6.16	6.58	6.61	6.52	6.84
Fossil fuel (gross)	19.37	20.12	20.54	20.32	20.07	19.97	20.58	20.93
Gas	2.94	2.71	2.87	2.88	2.86	2.83	2.74	3.05
Coal	15.17	15.85	15.99	16.19	16.03	16.21	16.79	16.91
Oil	1.26	1.56	1.69	1.25	1.18	0.95	1.05	0.97
Total transmitted electrical energy	**9.25**	**9.56**	**9.61**	**9.60**	**9.87**	**10.13**	**10.53**	**10.8**
Resident. & Comm.[d]	15.15	16.00	16.26	15.57	15.99	16.09	16.73	17.00
Industrial[e]	21.12	22.09	22.27	22.84	22.55	23.50	23.71	24.09
Transportation	21.42	22.27	22.55	22.50	22.09	22.43	22.86	23.33
Total consumption[c] (DOE/EIA)	**77**	**80**	**81**	**81**	**81**	**82**	**84**	**85**

Source: *Monthly Energy Review*, U.S. Department of Energy, DOE/EIA-0035(95/04) (April 1995); *Annual Energy Review—1994*, U.S. Department of Energy (July 1995).

[a]Strategic petroleum reserve storage began in October 1977.

[b]Excludes exports but takes account of refinery gains, SPR additions, and other stock changes as well as unaccounted crude oil.

[c]Note that this total is not the sum of entries above.

[d]Excludes electrical losses.

[e]Includes field use of natural gas and non-fuel category and excludes electrical losses.

Table 2. Gross domestic product by major type of product.
(Billions of constant 1987 dollars)

	1991	**1992**	**1993**	**1994**
Gross domestic product	4821	4986	5135	5342
Goods	1911	2006	2082	2222
Services	2498	2535	2598	2644
Structures	412	446	455	476

Source: *Survey of Current Business*, **75**, No. 2 (Feb. 1995) Table 1.4.

On the supply side (see left side of Fig. 1 and 2), petroleum remained the most important fuel for the economy. Imports of crude oil and petroleum products rose as domestic production continued to decline (Fig. 3). The next most important fuels were natural gas and coal, with natural gas contributing slightly more energy than coal. Use of natural gas increased in 1994 because of increased domestic production and larger imports from Canada. Among the fuels used to generate electricity: coal was near 1993 levels; natural gas showed a substantial increase; oil remained a fuel of necessity, and its decreased use (9%) was not out of keeping with fluctuations during the previous decade; and the decline in utility hydroelectric power was compensated for by an increase in output from nuclear power plants.

Supply and Demand of Fossil Fuels

Oil Supply

Domestic Production

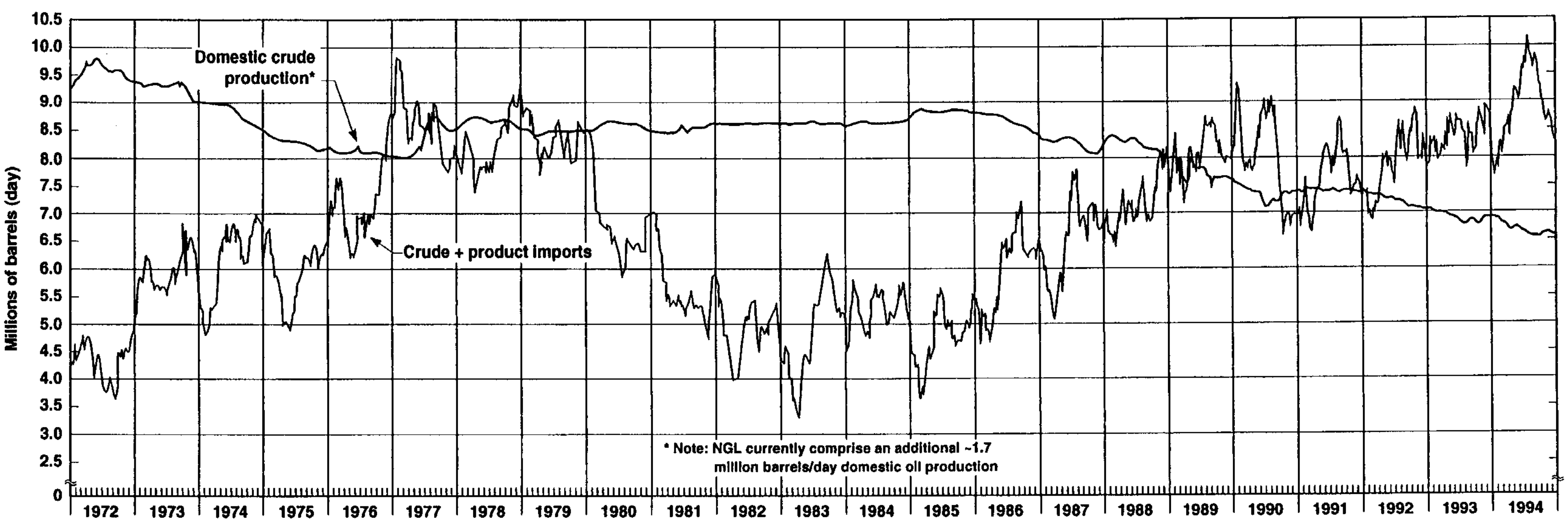
Oil production continued its inexorable decline. Production of crude oil fell 2.5%, while production of natural gas liquids (NGL), which comprise the second component of U.S. oil, remained stable.[6] Since 1973 NGL's absolute contribution to the total has remained fairly constant; however, its share has steadily increased from 16% to 20% at the end of 1994. Crude oil reserves fell for the sixth year to 22.9 billion barrels; NGL to 7.2 billion barrels.[7] Annual reserve additions for oil (and gas) are far below the level necessary to replace current production.[8]

Because of improvements in Alaskan North Slope production facilities several years ago, the rate of decline in Alaskan production was slowed to 2% from 8% the year before.[9] One bright spot was the fact that new field discoveries were the highest in 23 years—319 million barrels. Almost all were in deep waters of the Gulf of Mexico Federal Offshore area.

Figure 3. Petroleum imports and domestic production; refiner acquisition cost of crude oil.

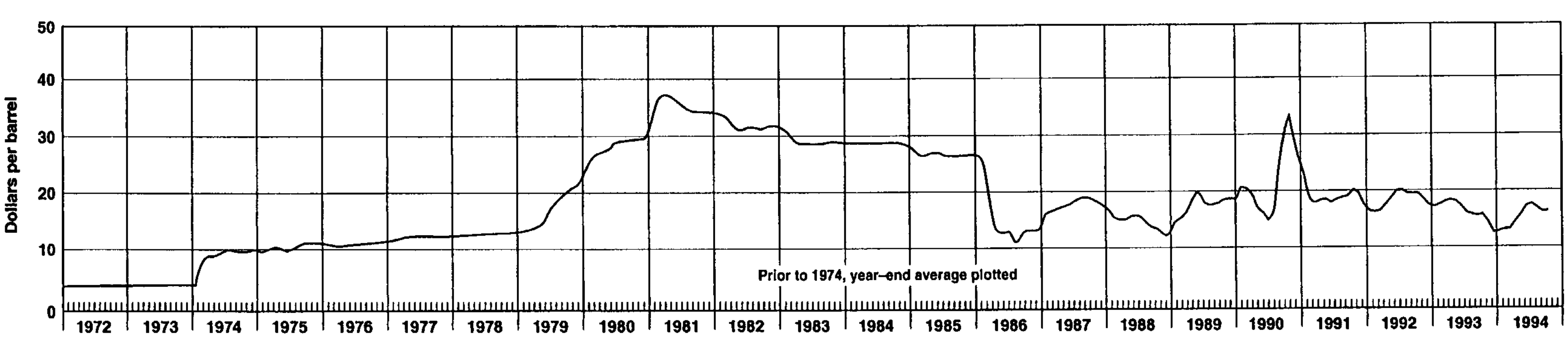
PETROLEUM IMPORTS AND DOMESTIC PRODUCTION

Moving four week average



REFINER ACQUISITION COST OF CRUDE OIL

Composite domestic and imported



Oil Imports Chart 1-24-95

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Prices for both domestic and foreign crude oil fell below 1993 levels (Fig. 3) and, when adjusted for inflation, below prices that prevailed prior to the 1973 embargo.[7] Conventional measures of exploration activity in the United States (number of wells drilled, footage drilled, rotary rigs in operation, number of active seismic exploration crews, etc.) also reached record lows in 1994. Major oil companies continued to move their activities overseas, and almost all have significantly cut the number of employees in the domestic production and refining end of operations.[10]

The issue of Alaskan oil exports arose again during the year with the release of a Department of Energy study recommending that the ban in effect since 1973 be lifted.[11] The most cogent argument for lifting the ban is that it would add 200–400 million barrels of Alaskan oil to the economic reserves by providing markets, principally in Asia, for oil that is not currently marketable on the West Coast. Lifting the ban is backed by the oil industry and the states of Alaska and California, which believe that the move would stimulate local production and produce jobs. Opposition has come chiefly from the U.S. maritime unions and shippers, currently the only legal carriers between U.S. ports, which potentially could lose some part of their business. The issue of energy security, which drove the adoption of the original ban in the earlier decade of oil crises, thus has become subservient to economic issues. The 590-million-barrel Strategic Oil Reserve, which did not exist when the ban was enacted, is cited as a factor that has changed the overall picture. However, there is some concern that gas and heat problems in the underground caverns storing the reserve have limited the government's ability to withdraw oil in an emergency.[11] At the end of the year, the issue of Alaskan oil exports had not been resolved.

Oil Imports

Net oil imports as a percentage of petroleum products supplied rose one percent to 45.2%.[4] In terms of volumes of oil imported, 1994 was not a record year; greater amounts were registered in 1977 and 1978. Principal suppliers of petroleum in 1994 (Fig. 4) were Saudi Arabia of the Arab Organization of Petroleum Exporting Countries (OPEC) (1.4 million barrels/day [b/d]); Venezuela, a non-Arab member of OPEC (1.3 million b/d); and Canada

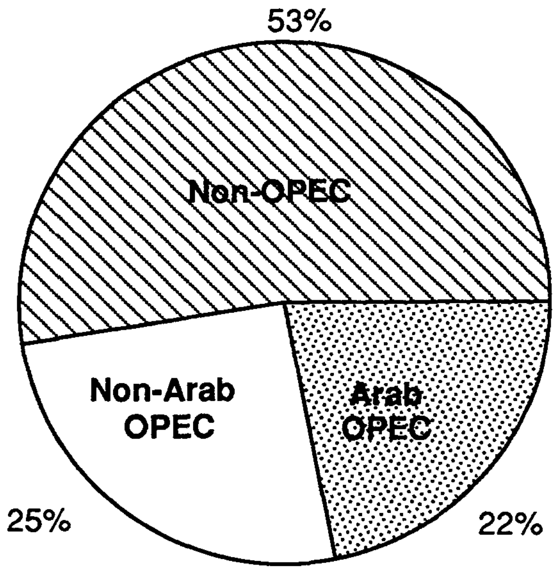

Figure 4. Source of U.S. petroleum imports in 1994.
Source: *Monthly Energy Review,* DOE/EIA-00035(95/04), U.S. Department of Energy, Washington, DC (April 1995) Table 3.3.

Oil Demand

Consumption of petroleum accounts for about 41% of annual energy demand, and thus oil products are the largest single source of energy to the United States. Petroleum demand rose slightly in 1994, in part because of extreme weather in many regions of the country during the first half of the year and in part because of a robust economy. Gasoline consumption rose 1.7%, close to the annual growth rate in the previous decade. Reformulated gasoline, an oxygenated fuel that is more completely combusted, began to be produced and marketed in some parts of the country before the January 1, 1995, deadline stipulated by the Clean Air Act Amendments of 1990. The transition to reformulated gasoline went smoothly. There were objections from federal lawmakers as well as from the petroleum industry to the Environmental Protection Agency's (EPA) proposed rule requiring that 30% of the oxygen content of the gasoline come from ethanol.[14] Ethanol is more expensive than methanol, the alternative source of the additive, and refiners claim that it would require special storage and pipeline facilities. Subsequently a federal appeals court ruled that the EPA cannot order the refiners to use ethanol as an additive.[15]

In the last decade, end use of petroleum products has changed appreciatively. Whereas use for heating, power generation, and other miscellaneous purposes has declined, demand in the petrochemical and transportation industries has steadily increased. Use of heavy residual oil fell 8.9% in 1994 alone.

Natural Gas Supply

Domestic dry gas production rose again in 1994 but did not match the production of any year in the 1973–1982 period. Reserves of natural gas at the beginning of the year stood at 162.4 trillion cubic feet (Tcf), down 1.6% from the previous year.[7] Dry natural gas production in 1993 of 17.8 Tcf was not quite balanced by combined discoveries (8.9 Tcf) and revisions and adjustments to reserves (6.3 Tcf) for a total of 15.2 Tcf. Gas producers have replaced more than 93% of production with reserve additions since the early 1980s.[16] Thus the adequacy of future supply or the number of years of production remaining from the nation's reserves cannot be predicted by simply dividing the size of the reserve by average annual production, as is sometimes done by novice forecasters. Two developments bode well for continued replacement of the gas annually produced from the reserve "pool." One is the major shift in focus from oil to natural gas exploration in the United States in the last decade, and the other is the simultaneous significant advances in technology that have improved finding rates.

Although imports (principally from Canada) have more than doubled since 1973 (Fig. 5), they currently comprise only 10% of supply. In addition, a small amount of gas (50–80 billion cubic feet) was imported in the form of liquefied natural gas (LNG) from Algeria. Imports of LNG reached record levels during the severe winter of 1994 in the northeast portions of the country.

The past growth of Canadian gas imports has been directly related to the construction of new pipeline systems into the Northeast, California, the Midwest, and the Pacific Northwest. Future growth depends on additional pipeline capacity. Although there are currently no totally new, major pipelines under construction between the United States and Canada, there are many projects in the planning or construction stage that are designed to increase capacity of *existing* systems.[17]

The pipeline industry is still in the process of conforming to the April 1992 Order 636 of the Federal Energy Regulatory Commission that required separation of sales, storage, and transportation activities. The order has resulted in the fundamental restructuring of the natural gas market. Customers, who formerly contracted for both gas supplies and transportation with the pipeline companies, must now purchase the gas themselves and contract only for

Figure 5. Growth in natural gas imports to the United States.
Source: *Annual Energy Review—1993*, DOE/EIA-0384(93), U.S. Department of Energy, Washington, DC (July 1994) Table 6.1; *Monthly Energy Review*, DOE/EIA-0035(95/03), U.S. Department of Energy, Washington, DC (April 1995) Table 4.3.

transportation capacity with the pipeline companies.[18] The changes, which were designed to introduce more competition into the industry, have not been smooth, especially for small customers with limited experience in the marketing of natural gas or the trading of pipeline capacity.

Natural Gas Demand

The 1.5% increase in natural gas use in 1994 brought consumption near the all-time record set in 1972, when the average real price (in 1987 dollars) of natural gas was $0.49 per million cubic feet (Mcf).[19] Steady price increases in subsequent years and a rigid regulatory environment were associated with a fall in demand in all end-use sectors. By 1983 the price had risen to $2.97 (in 1987 dollars) per Mcf. Although the price later declined, by 1986 demand was at a 20-year low.[20] Since 1986, when deregulation of the industry gained momentum, the price of natural gas has declined, and there has been a resurgence in gas demand. In 1994 the average wellhead price in real 1987 dollars was $1.44 per million cubic feet.

U.S. Energy Flow – 1994
Net Primary Resource Consumption 85 Quads

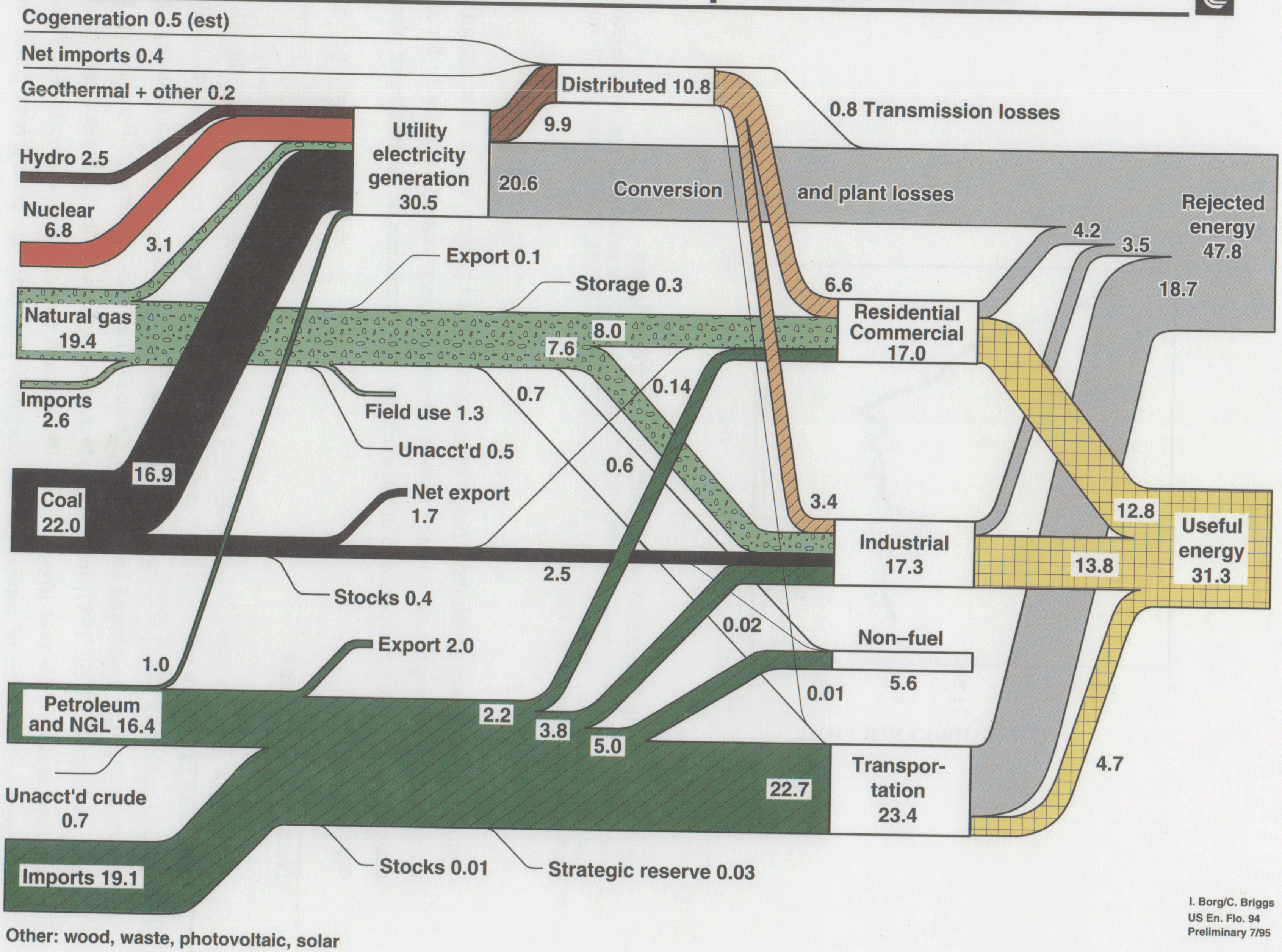

Figure 1. U.S. Energy Flow—1994. One quad equals one quadrillion (10^{15}) Btu's.

U.S. Energy Flow – 1993
Net Primary Resource Consumption 84 Quads

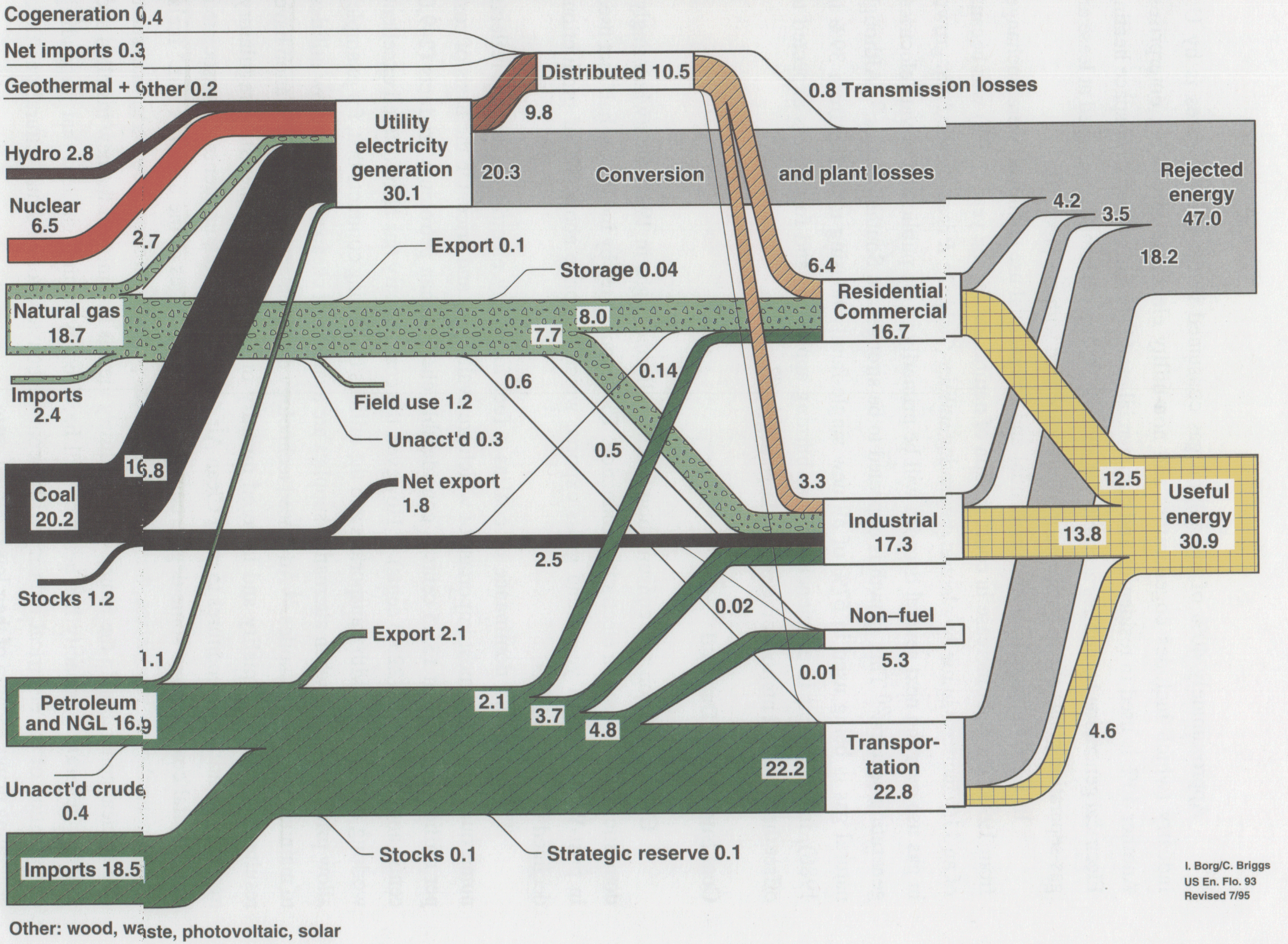

Figure 2. U.S. Energy Flow—1993, in quads.

Approximately 40% of the natural gas consumed in the United States is by U.S. industry (which includes cogenerators and non-utility electrical generating enterprises). Another 40% is used in residences and commercial establishments, chiefly for space heating. Electrical generation by utilities accounts for about 15%, and the remainder is used at lease and gas-separation plants and at compressor plants associated with gas pipelines.

In 1994, industrial use and residential-and-commercial use combined were unchanged from 1993. The total increase in consumption of natural gas for the year (1.5%) was because of an 11% increase in use by electric generating utilities (Table 1). It is anticipated that growth in gas use over the next several decades will be primarily in the public and private electrical generating sectors.[20] This growth is expected to be strongest in Southern states.[21] Although natural gas is being used in 67% of all new single-family housing units (up from 39% in 1986), improvement in efficiencies of gas-burning appliances and furnaces is expected to offset the increased number of users to a large degree.[22]

Coal Supply and Demand

Coal production and consumption reached all-time highs in 1994. Overwhelmingly, domestic coal was used in electricity production. The amount used by industry is half that used in post-World War II years; and gross exports, which comprise about 7% of production, declined for the third year.

The continued dominance of coal as a fuel for utility electric generation reflects numerous factors, the most important of which are availability and price. On the basis of cost per million Btu, coal at 135.5 cents is considerably cheaper than petroleum products (249.0 cents) and natural gas (223.0 cents).[23] However, the coal industry has also fostered excellent working relationships with transporters and the utilities by writing contracts that, for example, allow price reductions when alternative supplies are available at cheaper rates or allow utilities to maintain reduced stockpiles.[24] Advanced technology development and implementation have resulted in improved quality and lowered quantity of emissions. Further state regulatory treatment of utility expenditures to meet Clean Air Act emissions requirements and associated plant capital costs have to some degree countered the advantages of the use of "clean" fuels such as natural gas. Nonetheless, the coal industry sees potential erosion of coal's market share of electrical generation in the future.[25] The industry view is that most of the new installed and planned generating capacity has been, or will be, fired by natural gas and that impending deregulation of the electrical industry will encourage construction of small natural-gas-fired generating plants because of their lower capital costs.

Electrical Supply and Demand

Electricity distributed by the public utilities increased by almost 3% in 1994, in keeping with past trends that were interrupted only by the recession of the early 1990s (Fig. 6). As noted earlier, the growth of self-generators, who produce power for their own needs, has been substantial during the past decade and has been largely unmonitored by public agencies. As a consequence, the total use of electricity is understated in most tallies, such as those reported here. Sales to utilities by small power producers using a variety of fuels, however, are a matter of record. An estimate of their growing contribution is shown in Fig. 1 and 2, and data on their installed capacity and gross generation are given in Table 3. To put the amount of electricity generated by the group into perspective, total net utility generation and net imports in 1993 were 2882 billion kWh and 29 billion kWh respectively. Nonutility generators' output thus comprised approximately 10% of the total.

In order of importance, fuels used for power generation by the public utilities are coal, gas, nuclear, hydropower, and oil. Of these fuels, only the amount of natural gas used for

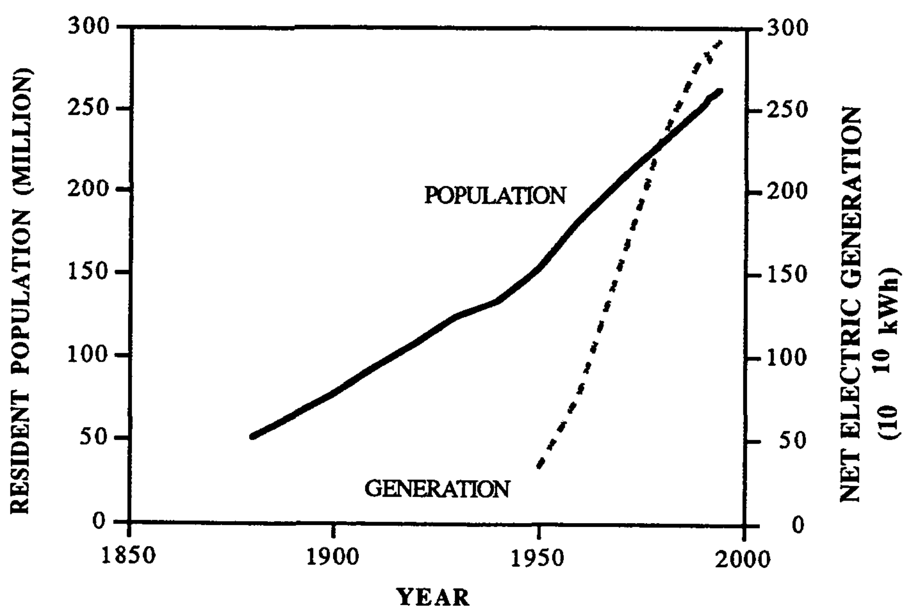

Figure 6. Growth of U.S. population and net utility electrical generation.
Source: *Annual Energy Review—1994*, DOE/EIA-0384(94), U.S. Department of Energy, Washington, DC (July 1995) Table 8.3; *Statistical Abstract of the United States—1994*, U.S. Department of Commerce, Washington, DC (1994) Table 2; *Monthly Energy Review*, DOE/EIA-0035(95/04), U.S. Department of Energy, Washington, DC (April 1995) Table 7.1.

Table 3. Installed capacity and gross generation of nonutility electric generators larger than 5 MW.

Year	Installed capacity	Increase (%) (GW)	Gross generation (billion kWh)	Increase (%)
1989	36.6		187.1	
1990	42.6	16.1	215.2	15.0
1991	48.2	13.2	248.5	15.5
1992	56.8	17.8	296.0	19.1
1993	60.8	7.0	320.6	9.9

Source: "Statistics on nonutility power producers," reprinted from *Monthly Energy Review* (August 1992 data) DOE/EIA-0035(92/10), U.S. Department of Energy (October 1992); *Electric Power Annual—1993* DOE/EIA-0348(93), U.S. Department of Energy, Washington, DC (December 1994) Table 1.

generation increased substantially in 1994. Natural gas is the preferred fuel of nonutilities, cogenerators and self-generators because of its clean burning characteristics and the lower capital cost associated with gas generators.

Deregulation of the Electric Power Industry

The Public Utility Regulatory Policies Act, which encouraged independent power production by requiring the public utilities to purchase nonutility-generated electricity, and the Energy Policy Act of 1992, which required the public utilities to transmit electricity generated by the independent power producers, set the stage for radical restructuring of the electrical power industry in the United States. These acts potentially give independent power producers access to big and small retail customers and give customers the opportunity to chose their supplier. By 1993 many states (e.g., Michigan, Wisconsin, Texas, New Mexico, and California) began to examine the implications of such changes and the likely new competition between the heretofore monopolistic public utilities and the independent power generators within their states. Moving rapidly, the California Public Utilities Commission (CPUC) in the spring of 1994 finished formulating a proposal to allow out-of-state utilities to sell power directly to large industrial and commercial users, starting in 1996, and to residential users in 2002. Hearings, which were closely watched by interested parties across the nation, began in June.

The objective of the CPUC proposal was to prod the public utilities to improve their efficiencies and cut their costs in order to meet the competition. The issues raised at the hearings proved the subject to be complex, and at the outset the principal utilities in the state could not agree on whether a new electric "pool" would be needed, i.e., in addition to the existing Western Systems Coordinating Council representing 11 member-states, which is part of the North American Electric Reliability Council.* Consumer advocates raised the prospect of the likely early loss of some of the utilities' large customers associated with relatively high profit margins and also raised the specter of compensating increases in the rates of the small users with large service requirements. The environmentalists feared the demise of energy conservation programs, of low-income subsidies, and of small nonutility generators that use unconventional fuels and whose electricity is purchased by the public utilities by mandate, often at uncompetitive rates. The question of how the existing utilities were to recover capital investments in generating facilities without a large rate base caused uneasiness in the financial community. Utility stocks and bonds, long regarded as stable investments, were viewed as potentially becoming more risky and more volatile in the marketplace. The ruling on the CPUC deregulation proposal was expected in early 1995; however, in March 1995 the CPUC announced that it had been indefinitely postponed, ostensibly until two vacant positions on the five-member commission are filled.[26] There is no indication when the seats will be filled, and further public comment will be required as well as scrutiny by the state legislature for at least three months before a final decision is made.

Some degree of deregulation is anticipated by the nation's utilities in the long term, and before this deregulation becomes a reality most utilities are focused on cutting costs and improving efficiencies to meet the anticipated future competition. At least one utility has entered into an agreement to transmit electricity for an out-of-state independent power producer who wishes to sell to major industrial users in that utility's service area.[27]

Nuclear Power

The year 1994 was memorable for the nuclear power industry. Work was officially halted on the last nuclear power plants under construction in the United States. In December 1995, the Tennessee Valley Unit 1, which was completed in 1985 and which underwent testing in 1994, plans to load fuel. If it does so, it will be the new last reactor in the United States to go on line in the foreseeable future.

Early in 1994, the Washington Public Power Supply System put two of its unfinished nuclear reactors on the market (WNP 1 at Hanford, WA, and WNP 3 at Satsop, WA) for $3.4 billion.[28] These reactors are respectively 65% and 75% complete. Columbia Nuclear

*The North American Electric Reliability Council (NERC) is responsible for setting and maintaining standards, criteria, and guides for planning and operating reliable bulk power electric systems or power grids. Within the NERC regions, "control areas" that consist usually of several utilities by contractual arrangements manage electric generation to meet demand and fulfill exchange obligations.

Corp., a consortium including Battelle Memorial Institute, has proposed that more than $7 billion be raised from private sources to finish both reactors and operate them with plutonium fuels. This "Isaiah Project" is touted as a way of safely disposing of weapons-grade plutonium that is accumulating as a result of dismantlement of warheads in both Russia and the United States. The idea is not new; at least three commercial U.S. reactors have used mixed plutonium/uranium oxide fuels in the past. There are 10 mixed-oxide civilian reactors operating in Germany, five in France, and two in Belgium. Further, in the future Japan plans to use in its reactors plutonium extracted from its conventional spent fuel rods during reprocessing.

Abandonments, shut-downs, and retirement of capital-intensive nuclear reactors before their anticipated life expectancy have set the stage for legal battles among owners, public utility commissions, and the Federal Energy Regulatory Agency (FERC) throughout the country as to whether the owners will be allowed to recover their investment. The Oregon Public Utilities Commission staff recommended that Portland General Electric be allowed only 80% of its unrecovered investment in the Trojan nuclear plant. The 1100-MW reactor was shut down and retired in January 1993 because its corroded steam generator was deemed too expensive to repair.[29] On the other hand, FERC ruled that Yankee Atomic Electric Co. was entitled to recover investment in the Yankee Rowe nuclear plant in Massachusetts, which was retired in 1992.[30] The Maryland Public Service Commission and Baltimore Gas and Electric Co. have disputed who—the rate payers or the utility—should pay for the added cost associated with power purchases when the utility's Calvert Cliffs, MD, reactors were shut down for approximately 1390 days in the 1989–91 period.[31] These arguments are certain to increase in number as more of the nation's aged reactors are retired. Almost half of the 109 nuclear reactors in the United States are older than 20 years.

A bright spot in the nuclear field is the steady increase in capacity factors for the operable reactors in the country. In 1994 the average stood at 74% (Table 4), almost 20% higher than the average a decade earlier. The improvement reflects not only the retirement of older, less-efficient, trouble-prone reactors but also successful programs designed to improve efficiencies and "down-time." A case in point is Pacific Gas & Electric Co.'s Diablo Canyon, CA, nuclear installation consisting of twin reactors. Because of a CPUC ruling that tied the rate of return on investment in the two reactors to the amount of electricity generated rather than to traditional cost-based determinations, the utility instigated a program designed to reduce the down-time associated with refueling. Down-time was reduced from 82 and 129 days for the two reactors to 59 and 57 days respectively in 1993 and to 57 and 34 days in 1994.[32] Combined with other efficiency measures, capacity factors for the two reactors have been in the 80–90% range for the past few years. For its efforts, the utility received 11.89 cents per kWh for nuclear power produced in 1994.[33]

Table 4. Electrical generation from nuclear power.

	Year 1991	1992	1993	1994
Total utility electrical generation (billion kWh)	2825	2797	2883	2909
Nuclear contribution (bn kWh)	613	619	610	639
Percent nuclear	21.7	22.1	21.1	22.0
Installed nuclear capacity[a] (GWe)	99.6	99.0	99.0	99.0
Number of operable reactors	111	109	109	109
Annual nuclear capacity factor (%)	70.2	70.9	70.5	73.7

Source: *Monthly Energy Review*, DOE/EIA-0035(95/03), U.S. Department of Energy, Washington DC (March 1995) Sec. 8.
[a]Net summer capability of operable reactors

The failure of the U.S. Department of Energy to provide a site for the storage of high-level waste and spent fuel by 1998, the date originally stipulated in the Nuclear Waste Policy Act of 1982, began to have serious repercussions for reactor owners in Minnesota. After 20 years of trouble-free performance, two reactors at Red Wing, MN (Prairie Island), have exhausted the storage space allotted for spent fuel; and an alternative storage acceptable to the federal and state governments and to the Sioux tribe, whose reservation shares the reactor's island, has not been forthcoming. Closing the plant would mean a substantial rate increase for customers, who now pay 1.5 cents per kWh.[34] Similar problems promise to surface for other of the nation's reactor operators, particularly if the date for opening a federal permanent repository is moved beyond the current amended date of 2010.

Appendix

Data and Conventions Used in Construction of Energy Flow Charts

Data for the flow charts were provided by tables in the Department of Energy's *Monthly Energy* Review,[4] the *Quarterly Coal Report,*[35] and the *Annual Energy Review—1994.*[36]

The residential and commercial sector consists of housing units, non-manufacturing business establishments, health and educational institutions, and government office buildings. The industrial sector is made up of construction, manufacturing, agriculture, and mining establishments. The transportation sector combines private and public passenger and freight transportation and government transportation, including military operations.

Utility electricity generation includes power sold by both privately and publicly owned companies. The non-fuel category of end use consists of fuels that are not burned to produce heat, e.g., asphalt, road oil, petrochemical feedstocks such as ethane, liquid petroleum gases, lubricants, petroleum coke, waxes, carbon black, and crude tar. Coking coal traditionally is not included.

The conversion and plant losses associated with utility electrical power generation are a matter of record. Transmission losses are the difference between total transmitted electricity and receipts by the principal end-use sectors. They are approximately 7% of transmitted electricity. In other sectors, such as residential/commercial, industrial, and transportation, the division between "useful" and "rejected" energy is arbitrary and depends on assumed efficiencies of conversion processes. In the residential and commercial end-use sectors, a 75% efficiency is assumed, which is a weighted average between space heating at approximately 60% and electrical motors and other electrical uses at about 90%. Eighty percent efficiency is assumed in the industrial end-use sector and a generous 20% in transportation. This is below the 25% efficiency we have used in past years. The latter percent corresponds to the approximate efficiency of the internal combustion engine as measured on the bench by "brake thermal efficiency" tests.

We have persisted in expressing these approximate efficiencies in our flow charts over the years, although we are fully aware of the changes in all end-use sectors that have modified actual efficiencies to some degree over the same time period. Unfortunately we lack quantitative data to improve our estimates. We feel, however, that despite improved mileage for highway vehicles, it is unlikely that transportation efficiencies in reality have reached 20% and certainly not the 25% associated with bench tests. In other end-use sectors, not only have some efficiencies changed but also the slate of fuels used by the various end-use sectors has changed, which influences the average efficiency for the sector. For example, electrical usage has steadily risen in the residential and commercial sectors because of increased use of air conditioners; natural gas has a bigger share of the heating market than in the past. We are uncertain of the net result of these changes. Another uncertainty has to do with the influence of cogeneration and self-generation of electrical power on overall industrial efficiencies. Clearly the magnitude of the effect relates to the percent of the waste heat associated with non-utility electric generation that is used in other industrial processes. Rather than abandon the approach because of uncertainties, we continue to estimate "rejected" and "useful" energy in order to point out which of the various energy sectors are associated with the largest absolute losses, such as electrical power production and transportation, and thus to direct attention to the most fertile ground for technological improvements.

There are some minor differences between the total energy consumption shown in the energy flow charts (Fig. 1 and 2) and the DOE/EIA totals given in Table 1. The industrial consumption total in Table 1 agrees with DOE's *net* industrial total. Both totals include natural gas lease and plant fuel and non-fuel ("non-energy") use, which are shown separately in the flow charts.

Conversion Factors

The energy content of fuels varies. Some approximate, rounded conversion factors, useful for estimation, are given below.

Fuel	Energy content (Btu)
Short ton of coal	21,400,000
Barrel (42 gallons) of crude oil	5,800,000
Cubic foot of natural gas	1,000
Kilowatt hour of electricity	3,400

More detailed conversion factors are given in the Department of Energy's *Monthly Energy Review.*

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